Service Date: January 4, 1982

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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In the Matter of Avoided Cost Based	)	
Rates for Public Utility Purchases	)	UTILITY DIVISION
from Qualifying Cogenerators and	)	DOCKET NO. 81.2.15
Small Power Producers.	)	ORDER NO. 4865

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APPEARANCES

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BEFORE THE MONTANA PUBLIC SERVICE COMMISSION:

GORDON E. BOLLINGER, Chairman
JOHN B. DRISCOLL, Commissioner
HOWARD L. ELLIS, Commissioner
CLYDE JARVIS, Commissioner
THOMAS J. SCHNEIDER, Commissioner

FINDINGS OF FACT

BACKGROUND

1. Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) required the Federal Energy Regulatory Commission (FERC), as well as state regulatory authorities, to prescribe rules to encourage cogeneration and small power production (COG/SPP) including rules requiring electric utilities to purchase electric power from cogeneration and small power production facilities. Among other things, the rules were to insure that rates for purchases of electric energy from qualifying facilities (QF) "be just and reasonable to the electric consumers of the electric utility and in the public interest" and that the rates would not exceed the "incremental cost to the electric utility of alternative electric energy."

2. On May 4, 1981 the Commission adopted final rules governing purchases and sales between public utilities and qualifying small power production facilities. The Commission rules are modeled after FERC regulations implementing Section 201 and 210 of PURPA. The rulemaking procedure featured a public comment period commencing with the issuance of draft rules on September 2, 1980 and extending through October 23, 1980. The draft rules, with proper notice, went to public hearing on October 23, 1980 in Helena, Montana. Testimony and/or comments were

received from the Montana Power Company (MPC), Pacific Power and Light (PP&L), Montana-Dakota Utilities (MDU), the City of Livingston, the Department of Natural Resources and Conservation (DNRC), and several individuals. A second, revised draft of the rules was issued on March 16, 1981 with public comment extending through April 27, 1981. Comments were received from MPC, PP&L, the Alternative Energy Resource Organization, the Energy Law Institute, and several individuals. The rulemaking proceeding ended with adoption of final rules on May 4, 1981.

3. The Commission's rules (ARM 38.5.1901 through 38.5.1908), pursuant to FERC regulations, provide the general obligations of the COG/SPP and the regulated electric utilities. The rules, however, left to a contested case proceeding the development of tariffs providing specific rates, terms, and conditions for service.

4. The Commission initiated this proceeding on February 24, 1981 when it requested that MDU, PP&L, and MPC file testimony regarding avoided cost methodologies, avoided cost-based rates, and tariffs and standard contracts for purchases of electricity from COG/SPP.

5. When the Montana Consumer Counsel declined to present a case in this docket, the Commission created the Commission Advocacy Staff for the purpose of providing testimony concerning the instant issues independent of each utility's case. Ms. Eileen Shore, Chief Counsel, was assigned to head the Advocacy Staff, and Drs. Thomas M. Power and John Fox were hired to provide expert testimony. Additionally, Mr. Robert Olson assisted Ms. Shore in the presentation and preparation of Advocacy Staff's case.

6. Pursuant to the procedural order dated April 13, 1981, Rural Energy Development Foundation (REDF) and Alpha Engineers, Incorporated were granted intervention status. REDF participated to a limited extent throughout the proceeding; Alpha Engineers, Inc. withdrew their intervention status immediately before the hearing.

7. Public hearings were held on September 29 and 30, 1981 in the district courtroom of the Federal Building in Helena, Montana. Parties were given an opportunity to cross-examine one another and other interested persons, including engineer James Barber of JUB Engineering, Inc. of Boise, Idaho and economist Dr. Lawrence Nordell of the Montana Department of Natural Resources and Conservation, presented statements to the Commission.

8. For explicatory purposes, and commensurate with the Commission's rules, the major issues have been divided into two categories: standard tariff rates and tariff and standard contract terms and conditions. Analysis of each issue will include a brief summary of the parties' testimony and pertinent Commission rule when necessary, followed by the Commission's determinations on a general basis. Any utility-specific matters will be resolved at the end of each section.

STANDARD TARIFF RATES

Policy

9. ARM 38.5.1903(2) reads, in part, that "...each utility shall purchase any energy and capacity made available by a qualifying facility: (a) At a standard rate for such purchases which is based on avoided costs to the utility as determined by the Commission; or (b) If the qualifying facility agrees, at a rate which is a negotiated term of the contract between the utility and the facility..." ARM 38.5.1901(2)(j) defines standard rates as "those rates calculated by a means approved by the Commission which ...are based on avoided costs to the utility, are computed annually and made available to the public, are reviewed by the Commission, and are applicable to all contracts with qualifying facilities which do not choose to negotiate a different rate..." Thus, the Commission's intent, in respect to tariff rates, is to establish regulated rates to which all qualifying facilities (QFs) are entitled in exchange for the sale of power to the utilities. The tariff is only an option--an alternative to negotiation.

10. Prior to a discussion of the relative merits of each proposal and the resulting findings, the Commission wishes to set forth several critical policy findings.

11. The Commission recognizes that any deviation from full or complete avoided costs, either on the high side or low side, results in an adverse affect on ratepayers. Thus the primary objective in developing rate calculation methods is to allow rates which most accurately reflect full avoided costs. "Full avoided costs" is interpreted here to represent 1) exhaustiveness in cost components and, when appropriate, 2) long-run incremental costs.

12. A second goal in the Commission's deliberation is moderation, or gradualism. The Commission has found several substantial unknowns and thus has attempted to find some middle

ground balancing the unknowns between the low side and high side of the true avoided costs. The Commission intends to encourage the progressive refinement of the methods and will entertain constructive criticism and evidence at each annual filing of proposed tariffs. If conclusive evidence is submitted suggesting the methods developed herein need refinement, then the Commission will revise the methods with grandfathering provisions as deemed necessary.

13. Both MDU and PP&L argued that the methods they proposed represent methods suited to their unique systems, are accepted by other state Commissions, and that any deviation from those methods would cause the incurrance of needless additional administrative costs. Although the Commission has neither gone out of its way to develop uniformity nor to maintain the PP&L and MDU proposals, it finds that it is the utilities, not the Commission, who are best equipped to deal with the increased costs of differing methods. The Commission is establishing only an option available to all QFs and the companies are free to negotiate rates utilizing their proposals. Furthermore, the Commission has found portions of their proposals unacceptable for purposes of a standard tariff and has found that the utilities are similar in that they are all experiencing load growth with similar generation expansion plans.

Energy

14. In structuring energy payments all three utilities make some type of distinction between firm and nonfirm QF. Nonfirm energy rates, in all three cases, reflect short run incremental running costs via some form of production modeling, e.g. system lambda. The utilities diverge however in structuring firm energy rates. MPC uses the same production modeling effort but provides a 5 mill bonus for firm performance. MDU goes to the running cost of a baseload plant with the fixed costs added to reflect capacity. PP&L further distinguishes long-term firm from short-term firm. Short-term firm is, on an interim basis, treated as nonfirm while long-term firm is paid energy depending on specific resource(s) avoidable and ability to follow load.

15. The Advocacy Staff proposes a calculation of avoided energy costs which does not distinguish between nonfirm and firm energy and which does not utilize production modeling, or short run marginal costs, but focuses on the energy function of base load plants.

16. The key to evaluating the alternative calculations of avoided energy costs lies in the purported relationship between short run incremental energy costs (e.g. system lambda) and the incremental energy costs of bringing on line a coal-fired baseload steam plant.

17. The Commission has been presented testimony in this proceeding as in several other proceedings, suggesting that the concept of fuel savings and optimal system planning necessarily, or at least theoretically, equate a rolling average system lambda with the energy-related cost of baseload expansion. In the case of MPC, Dr. Power (Exh. M, p.20-22) provides calculations which suggest that the theorem is correct -- at least for the period July, 1981 to June, 1982.

18. The Commission however, is not convinced that the system-lambda-equal-energy-related-baseload-generation-costs theorem is correct when applied to systems characterized by load growth, hydro resources, and limited thermal peaking and/or cycling capacity. The Commission feels that a system with peak shaving hydro storage capability or a system with a relatively high load factor, in both cases resulting in little or no thermal peaking or cycling capability, lambda will be dominated by the running costs of baseload plants. An example exemplifies this situation. MPC's forecast of system lambda (Exh. B; Exh. TAL-2 p.1) projects a 56 percent real <u>decrease</u> in the load weighted average system lambda between 1980 and 1990 (4.5 percent annual average). Despite the projected decrease in system lambda, or marginal energy costs, over the same time period the company projects (The Montana Power Company, 1981-2000 Projection of Loads and Resources February, 1981 and the Montana Power Company Forecast of Electricity and Natural Gas Prices 1981-1990, March, 1981), real total or average costs to <u>escalate</u> 81.6 percent (6.1 percent annual average). The latter figure represents annual real increases (over and above inflated operating expenses) of 18.78 percent in 1984, 15.02 percent in 1985, and 15.07 percent in 1990; reflecting Colstrip #3, Colstrip #4, and Resource 89, respectively. Evident is some substantial divergence between system lambda and long-run incremental energy costs. The long-range plans of all three utilities include no less than nine baseload plants prior to 1990.

19. In the short run, for example, one contract year or one test year, system lambda (or its equivalent short run production modeling) does represent the time differentiated costs the utilities will avoid by purchasing QF production. However, it is not system lambda, but coal-fired steam

plants that the utilities have recently brought (Coyote #1, Jim Bridger) or will soon be bringing (Colstrip #3) to the Commission in search of additional revenues. It is these plants, not system lambda, that has and will result in substantial (perhaps drastic) increases in the utilities' costs and consumers' rates. Thus the Commission finds that energy rates must reflect both system lambda in the short run and the baseload alternative in the long-run.

20. The avoided energy cost discussion to this point has addressed only avoided generation costs. The record in this proceeding has not provided the Commission a sound basis for establishing avoided energy-related line loss and transmission costs. Whereas the existence of a net avoidance of transmission is not clearly established, the record costs, although logical, indicates (e.g. Jordan Exh. O, p. 4, Barber Tr. p. 49) that some unknown amount of line losses will be avoided. Marginal line losses are substantial. MPC witness Bruce Ambrose calculates (Exh. 13, Sch. 1) a secondary energy loss factor of 30.5 percent and 26.1 percent for the winter and summer periods, respectively. Electric rate case proceedings for MDU and PP&L have indicated marginal line losses of similar magnitude. The Commission finds unacceptable the utilities and Advocacy Staff's proposed rates which simply ignore line losses. The proper approach is to establish some nominal energy loss factor subject to refinement with utility-specific analysis. For purposes of the initial tariffs, the Commission finds appropriate an energy loss factor of 8.3 percent. This factor represents the approximate load weighted average of transmission level energy losses calculated by Mr. Ambrose for the MPC system.

Capacity

21. The Commission has been presented four distinct proposals for structuring capacity payments. The three utilities' proposals are similar in that they reflect the possible deferral or avoidance of a specific avoidable generating plant. In the case of PP&L, 22 percent of the Wyodak #2 baseload plant (1986 recently deferred to 1988) is used to calculate avoided capacity. MDU also uses baseload expansion plans (1985) but proposes the entire fixed costs as potential capacity payments. MPC uses a 1985 gas-fired combustion turbine which was in their 1980 long-range plan but has since been deleted from the Company's expansion plans.

22. The capacity payments to QFs in each case are a function of the beginning year of the contract (1982-1988), length of the contract (5-35 years), industry construction inflation indices (generally, 6 percent to 10 percent), discount rates for discounting future cost avoidance (4 percent to 6 percent), and a qualifying performance criteria (capacity factor of 65 percent - 75 percent). The utilities' proposals do not recognize partial or aggregate capacity payments to QFs who do not meet the performance criteria and grant full payment to those above the criteria level with a full length contract beginning the year the avoidable plant is scheduled to come on line. All three utilities' offer some level of prepayments for capacity provided prior to the 1985-1988 period, but it is not clear whether these discounted prepayments in any way reflect expected avoidance of system planning (engineering studies, siting, etc.) efforts. Payments for capacity contracts of less than full duration are discounted to reflect the inflated costs of building the plant beyond the deferral period (or length of contract).

23. The Advocacy Staff's proposal differs primarily in how and to whom the payments are made, the payments are calculated and not necessarily in the calculation of avoided capacity. The Advocacy Staff's proposal utilizes a combustion turbine to estimate the exclusively capacity-related value of baseload expansion. Whereas the utilities discount pre-on line capacity (1982-1985 or 1988), the Advocacy Staff's proposal features full prepayment of capacity. The Advocacy Staff, rather than levelizing the discounted sum of inflated costs over the life of the contract, annualize capital costs in terms of constant contract year dollars. A third area of major difference lies in the concept of partial capacity payments. The Advocacy Staff, as opposed to a make-or-break performance criteria, proposes partial capacity payments based on the QF's expected reliability relative to that expected of a combustion turbine.

24. The Commission in reviewing the capacity rate proposals of each utility found unnecessary complexity a predominant characteristic. For purposes of a standard tariff, updated at least annually, the Commission finds persuasive the Advocacy Staff's proposal to simply annualize the cost of a combustion turbine in constant contract year dollars. The Commission also finds merit in the concept of partial capacity credits and the recognition of aggregate QF capacity. The Commission is less sure in respect to the merits of full prepayment. However, in light of the fact that

1) the magnitude of a full capacity payment is only in the area of four to seven mills, 2) the utilities do incur system planning costs (engineering studies, siting, etc.) prior to the on line dates, and primarily 3) the fact that several "full avoided cost" components (e.g. remote siting transmission, line losses, etc.) are not fully accounted for, leads the Commission to believe that full prepayment will not error on the high side of truly avoidable costs. The Advocacy Staff's capacity proposal accepted by the Commission is essentially that practiced by the utilities in recovering capacity-related revenues.

<u>Rates</u>

25. Commensurate with these findings, the Commission directs the utilities to develop a tariff providing rate schedules for two classes of QFs -- short-term and long-term. One class is to be comprised of Qfs unwilling or unable to commit themselves to a performance contract of at least four years. The second class is to consist of all QFs who are willing and able to sign a contract of at least four years duration. It should be pointed out that there is no explicit distinction here between firm and nonfirm -- the pricing provisions of each schedule will dictate an implicit distinction. The short-term/long-term distinction is made in anticipation that the system planners, in the initial start up period only, will require four year contracts with appropriate penalty provisions for incorporating QF loads into projections of system resources for purposes of designing system expansion plans.

<u>Short-Term Rates</u>

26. The short-term QF's energy rate schedule shall reflect short run incremental energy costs as determined from the utilities' production modeling efforts. The rate shall reflect a one contract year projection of annual load weighted average system lambda (or equivalent measure of short run incremental energy costs) and shall include the appropriate calculations of variable O&M, revenue requirement associated with working capital, and the nominal energy loss factor.

27. The Commission, initially, leaves to the utilities the option of establishing a short-term time differentiated rate schedule reflecting the companies' short run cost variation. The utilities are encouraged to structure time differentiated rates featuring seasonal, monthly, and/or daily rating

periods. The relatively higher general level of sophistication on the part of QFs presents a challenge to structure rates most accurately reflecting costs. The companies' proposals will be scrutinized and adjustments made on an as needed basis. It should be pointed out that only MPC's proposal does not feature optional time differentiation, even with evidence of substantial seasonal cost variation.

28. In addition to the energy rate, the short-term option -- both annual average or time differentiated -- shall include a nominal aggregate capacity credit. For purposes of the initial tariffs and until convincing evidence is provided to suggest otherwise, the aggregate capacity payment shall be calculated by assuming a 42.5 percent availability level relative to an assumed 85 percent combustion turbine availability. That is, short-term QFs will receive one-half of a full capacity payment added to the energy payment using the assumed 85 percent load factor for converting the annualized capital costs into a Kwh payment.

29. The Commission again leaves to the utilities the option of time differentiation with respect to the nominal aggregate capacity payment. The utilities, should they desire to develop time differentiation in the initial tariffs, or the 1982 tariffs, must use hourly loss of load data for structuring the differentiation. That is, while the annual average aggregate capacity payment is spread over all hours, the time differentiated option would spread the same aggregate capacity payment over those hours, as indicated by loss of load probability, where the utility is most likely to be capacity short.

<u>Long-Term Rates</u>

30. The second class of QFs are those who are willing and able to commit themselves to a contract of at least four years with appropriate penalty provisions for failure to deliver contracted capacity. These long-term QFs shall be paid an energy rate reflecting the energy-related generation costs associated with baseload expansion and a capacity payment reflecting the remaining capacity-related baseload expansion costs.

31. The utilities are directed to develop a long-term rate featuring an energy component based on the cost (current contract year constant dollars) of the projected running costs of the next baseload plant. Added to the running costs are the fixed costs associated with bringing on line a base

load plant less the capital costs associated with bringing on line a combustion turbine. In addition to the energy payment, a separate annualized capacity payment based on the costs of a combustion turbine paid in proportion (above, as well as below) to a 85 percent availability factor is to be developed. The capacity payment can be structured on a monthly or annual basis.

32. As with the short-term option, the Commission encourages the utilities to structure a time differentiated suboption featuring time differentiated energy and capacity rates based on system lambda and hourly loss of load probability, respectively. The time differentiated energy rate shall feature the same baseload plant costs, but allocated to rating periods commensurate with system lambda. The separate time differentiated capacity payment, however, provides an opportunistic alternative to the nontime differentiated partial capacity payment. Rather than partial capacity payments reflecting the QF's probability of providing capacity as needed, the time differentiation can allow for full capacity payments in exchange for QFs capacity provided in the hours most likely to correspond with capacity shortage. Depending on the level of differentiation, hours with less probability of capacity shortage should feature something less than full capacity. The Commission has left the time differentiation, at least initially, an option to the utilities. The utilities are encouraged to develop time differentiation (seasonal, monthly, and/or daily) in its offerings of long-term capacity payments.

33. The long-term costs shall be calculated and rates structured such that long-term energy and full capacity rates fully account for the annualized costs of owning and operating baseload plants. In the case of MPC, those costs shall reflect the costs of Colstrip #3 and #4, averaged. This overcomes the problem of relating common facilities to individual plants. MDU shall use Antelope Valley #2 and PP&L, Wyodak #2. The calculation of costs is to be exhaustive including coal, fuel inventory, taxes, insurance, administrative and general, O&M, as well as the nominal line loss factor of 8.3 percent. The costs of the combustion turbine used as a proxy to determine the portion of baseload expansion related solely to the capacity function, must be equally exhaustive and based on reasonable combustion turbine alternatives to QF's capacity and must reflect costs consistent with actual costing experience or industry estimates. All costs are to be stated in constant contract year

dollars, to be updated each June 1, for the contract year beginning July 1st, to reflect 1) refined resource plans, 2) more accurate and/or complete cost information, and 3) inflation, according to standard industry practice.

34. Capital costs are to be annualized by applying the companies' overall incremental cost of capital including tax effect -- not embedded cost of capital -- and shall be updated annually to reflect the contract year capital market. Finally, for purposes of converting baseload capital costs into energy rates, each utility shall use an assumed baseload capacity factor of 70 percent. The 70 percent reflects the Commission's attempt at some middle ground, but is certainly an item open to future refinement and utility specific experience if it exceeds average industry or regional performance.

Procedure

35. Appendix A provides a summary of the rate schedules to be developed in compliance with this Order and Appendix B provides specific direction in costing to be followed in arriving at costs pursuant to this Order.

36. In submitting initial tariffs in compliance with this Order, and proposed revised tariffs each June 1st thereafter, each utility is directed to provide 1) the proposed tariffs, 2) the calculated avoided costs used in arriving at the tariffed rate schedules, and 3) detailed working papers. The tariffs are to include, in addition to the rate schedules, the terms and conditions for service and the standard contract, in compliance with this Order. The avoided costs must include, at least, five year projections (beginning with the contract year) of: 1) the average annual system lambda (or equivalent short run production modeling), 2) time differentiated system lambda and/or loss of load probability supporting the time differentiation, 3) baseload running cost and capital cost calculations detailed by component, 4) detailed combustion turbine calculations, and 5) the estimate of overall marginal cost of capital. These five year projections must be presented in both constant contract year dollars and in nominal terms. These avoided cost data satisfy and supplement the requirements of ARM 38.5.1905(1). The working papers must provide the source and derivation of the costs, including incremental cost of capital, and provide the transformation of costs into rates. In the case

of the baseload costs, the working papers must include the most recent version of the actual engineering cost study, revealing projections of costs by component by time of incurrance from the time of initial planning to on line production. If available, the actual engineering cost studies supporting the estimated combustion turbine avoided costs must also be provided.

37. As all parties become experienced in QFs production, the Commission encourages further pursuit of a progressively refined treatment of structuring QFs rates. Several obvious items requiring refinement are the 42.5 percent availability assumption in calculating aggregate capacity payments, the 70 percent baseload and 85 percent combustion turbine production factors, the 8.3 percent line loss factor, and appropriate inflation factors. The utilities are directed to investigate avoided line losses, avoided transmission costs, and avoided reserve requirements. The Commission intends to expand the role of these factors in the calculation of the 1982 standard rates. The utilities are directed to provide evidence in their June 1, 1982 filing detailing appropriate transmission, line loss, and reserve requirement values to be included in the calculation of each rate schedule.

38. The tariff providing rates as found appropriate by the Commission precludes the use of "opportunity cost," "performance incentive," "levelized," "time of delivery," "retail rates," fixed capacity/variable energy," etc. payment schemes for purposes of a tariff, only. The Commission has merely established a payment option available to all QFs. The utilities and the QFs are encouraged to negotiate at will in a business-like atmosphere. For example, if PP&L finds that its tariffed short-term energy rate is too low and that it can offer its "opportunity cost" rate with no effect on ratepayers, then the Commission in no way intends to restrict that offering. The Commission, in its rules, did not require wheeling under the assumption that the utilities would, in good faith, utilize opportunity cost concepts in providing QFs access to lucrative regional markets with no effect on ratepayers. If the Commission finds its "good faith" assumption in respect to opportunity cost and wheeling, as well as other options provided herein, was in error, then it will readdress these provisions. Likewise, the offering of levelized or front loading contracts as required by ARM 38.5.1903(2)(b), fixed capacity/variable energy contracts, and performance incentives is in no way restricted by this Order. The innovative contracts resulting from negotiation should be the prime mover in the purchase of QF's energy.

39. Lastly, the Commission wishes to remind the utilities that ARM 38.5.1903(8) requires each utility to "upon initial contact with a potential qualifying facility, provide the potential qualifying facility with one (1) copy of: a) these rules, b) the Commission's approved standard provisions tariff, and c) the Commission's standard complaint procedure." ARM 38.5.1908 requires each utility to provide the Commission with one copy of the utility's initial written response to the potential qualifying facility. In addition to these provisions of information, the Commission contemplates a utility sponsored working conference to be held in each utilities service area for purposes of providing information to potential QFs.

TARIFF AND STANDARD CONTRACT TERMS AND CONDITIONS

40. ARM 38.5.1902(5) reads, in part, that "All purchases...shall be accomplished according to the terms of a written contract between the parties or in accordance with the standard tariff provisions as approved by the Commission. The contract shall specify:

(a) The nature of the purchase and sales;
(b) The applicable rate schedule or negotiated rates for the purchases and sales;
(c) The amount and manner of payment of interconnection costs;
(d) The means for measurement of the energy or capacity purchased or sold by the utility;
(e) The method of payment by the utility for purchases, and the method of payment by the facility for utility sales;
(f) Any installation and performance incentives to be provided by the utility to the qualifying facility;
(g) The services to be provided or discontinued by either party during system emergencies;
(h) The term of the contract;
(i) Applicable operating safety and reliability standards with which the qualifying facility must comply;
(j) Appropriate insurance indemnity and liability provisions."

Commensurate with the rules, the Commission's intent here is to resolve contested issues with respect to the specific terms and conditions for service under the standard tariff.

41. The utilities propose that all QFs be required to execute a written contract prior to interconnection. Accordingly utility-sponsored testimony contains tariff and standard contract proposals in varying degrees of length and complexity.

42. To promote understanding of party responsibilities and to minimize uncertainty as to allocation of risks, for the present, the Commission finds that all QFs should be required to sign a standard contract, containing the terms and conditions of service, for a minimum term of one year. The standard contract is to be a component of the QF's tariff -- approved, regulated, and maintained by the Commission. The standard contract should concisely set forth the options available to QFs regarding short and long-term purchase rates and terms and billing and payment alternatives, and the QF's choice should be clearly specified therein. To the extent practicable, definitions, technical specifications, and computations and/or formulas for payment determinations should be confined to appendices to the standard contract. Terms and conditions made redundant by Commission rules should be excluded from the QF tariff and standard contract.

BILLING ALTERNATIVES

43. Contrary to Commission rules, (ARM 38.5.1903(5)(c) and 38.5.1905(6)), each of the utilities confined their standard billing proposals to simultaneous sale and purchase arrangements. Their exclusion of any net billing option was premised on two contentions: (1) that the reliability of meters, not specifically designed to run backward and forward, was suspect; and (2) that valuable information concerning the production characteristics of QFs, individually and in the aggregate, could not be captured by a single meter.

44. Dr. Power maintained that the net billing option should be available to small QFs as such an option would minimize transaction and metering costs. On cross-examination, Dr. Power agreed that there was value to gathering information on the actual generating characteristics of small QFs but he questioned the cost-effectiveness of mandating dual meters for every QF when a sampling technique might provide the same information at a lower cost.

45. The fact the utilities are united in opposition to net billing, in combination with some of Dr. Power's statements regarding the concept, indicate to the Commission that there is a general lack of understanding, concerning the net billing option per the Commission's rules.

46. Dr. Power stated that in his opinion only very small QFs would opt for net billing, and that their motivation would be to avoid additional metering charges. In addition, he testified that

the concept of net billing presumes that a utility's avoided costs and its retail rates are roughly approximate. Dr. Power then concluded that "[a]nybody who was in the range displacing all of their consumption certainly would be better off opting for some other arrangement than net billing." (Tr. B-115).

47. The Commission would clarify that net billing was premised on two assumptions: first, that the state of the art of metering is such that a single meter, whether currently in place in Montana or not, can accurately record net consumption or production within a given billing period, thus avoiding the cost of the second meter; and second, that up until the point a QF becomes a net producer, the QF is logically entitled to be billed for his/her net consumption at the retail rate.

48. Once during a billing period, a QF becomes a net producer, the costs the utility avoids in purchasing the QF's energy are accurately reflected in avoided cost, not retail, rates. The Commission wishes to dispel any notion that a QF who opts for net billing would receive any rate other than the utility's avoided cost rate for its net production. This finding confirms what is explicitly stated in ARM 38.5.1905(6).

49. PP&L's proposed tariff implicitly recognizes the attractiveness of net billing wherein they give large QFs the option of offsetting their local load and then delivering any excess energy to the company at avoided cost rates. Likewise, PP&L's revised contract appears to endorse, to the exclusion of any simultaneous sale and purchase arrangements, a modified net billing approach via their definition of "Net Metered Output." In both instances, however, the amount subject to net billing is determined not by one but two meters.

50. The Commission finds merit in collecting QF production data, but it believes that there are means to accomplish such without abrogating the Commission rule that gives a QF the option of operating in parallel on a net billing basis. The utilities were given two hearing and public comment opportunities in the Fall of 1980 and the Spring of 1981. The Commission finds that the issue was resolved in those proceedings as reflected in ARM 38.1905(6). Should the utilities find a second meter necessary, then the utility shall provide the second meter (as PP&L has proposed) and make QF payments, upon request, under the net billing option. The Commission would note that by placing the cost of the second meter on the utilities, to the extent that meters currently in use

cannot reliably track net consumption or production, the utilities will have incentive to stay abreast of development regarding single meters that were specifically designed to operate on a net basis.

51. PP&L's definition of 'Net Metered Output' should be amended because it necessarily forecloses QF selection of a simultaneous sale and purchase arrangement.

52. These findings should serve to explicitly clear the air with respect to standard billing options. In summary, the QF has the option, upon request, of 1) simultaneous purchase and sale whereby all QF production is measured via a second meter, at the expense of the QF, and is purchased at the appropriate tariff schedule; and 2) operating in parallel with a single meter measuring net consumption or production. Net consumption is billed at the appropriate retail tariff schedule and net production is purchased at the appropriate QF's tariff schedule. If the utility deems a second meter necessary for either billing then it remains the utilities' integrity or data collection prerogative to install a second meter at no cost to the QF.

53. In a related matter the Commission finds MPC's and PP&L's billing procedures, as set orth in Appendix A and Articles IV and V of their respective contracts, to be unnecessarily convoluted. Mr. Jordan=s suggested alternative should suffice to adequately meet the needs of QFs and utility alike, without excessive rigmarole: within 15 to 20 days after the billing period had ended, the utility should make payment to the QF. A statement showing the amount of energy delivered to the utility's system during the billing period and the computation of the payment amount should be included with each payment.

54. The Commission finds MDU's 600 KWH per month ceiling on energy purchases from QFs of 100 KW or less to be inconsistent with Commission rules and MDU's policy to purchase all energy available from QFs. That restriction should be deleted from MDU's tariffs.

Interconnection Payments

55. ARM 38.5.1904(2)(c) provides that, if the utility installs interconnection facilities for the QF, the QF must reimburse the utility but "[the] reimbursement may be accomplished by means of amortization over a reasonable period of time within the term of the contract." ARM 38.5.1902

(5)(c) specifies that "the amount and manner of payment of interconnection costs" be set forth in the contract.

56. The Commission would reiterate that the issue of payment of interconnection costs was settled in the rules. MDU and PP&L are directed to amend their standard contracts to provide some method using reasonable financing charges for QFs to amortize such costs. The Commission is aware that instances may arise where a QF has as ready access to financing as do the utilities, however, absent guidelines as to how to distinguish which QFs need help financing interconnection costs, the amortization rule will be available to all QFs.

57. The Commission also determines that, once intertie has been accomplished between the utility and QF, the utility, not the QF, should be financially responsible for any alterations or modifications that are necessitated by a change in the utility's system voltage.

Insurance

58. The utilities proposed that the QFs be required to maintain liability and, if a capacity supplier, property damage or destruction insurance. Suggested floors for liability limits ranged from $500,000 to $1,000,000 per single occurrence, and property insurance provisions required that the utility be named insured as well as receive any proceeds, pending QF replacement of destroyed or damaged facilities. In addition, liability insurance proposals from MPC and PP&L give the utility unilateral power to require the QF to purchase additional coverage.

59. The Commission is reluctant to mandate comprehensive liability insurance coverage that would include explosion, collapse and underground hazards and contractual liability, without more information as to the cost of such insurance and a better justification as to why such insurance is essential to purchasing electricity from a QF. For the time being, the Commission will require only general liability insurance provisions in standard contracts. The Commission will permit the utilities to increase liability limits, whenever they see fit, only if such requests are made in good faith and upon reasonable justification.

60. The Commission finds the record to be insufficient to justify distinguishing liability insurance limits on the basis of QF size, therefore, the Commission leaves to the initiative of

insurance companies to differentiate premiums that reflect adequate liability coverage given a particular QF=s size and operating characteristics.

61. The Commission finds the utilities' proposals for property insurance to be particularly lopsided. The combination of named insured treatment, and receipt and retention of proceeds in anticipation of proof of replacement expenditure, could necessitate duplication of policies by the QF. The Commission understands the utilities desire to have access to a source of funds should the QF be destroyed and performance be discontinued, however, there is not necessarily any direct relationship between the cost of replacing a QF and the damages the utility will face as a result of the disruption. Absent a better explanation for the need for such requirements, the Commission finds the standard contracts need only contain a provision requiring capacity suppliers to obtain and maintain adequate property insurance; named insured and proceeds requirements should be deleted.

62. In light of the Commission's decision to allow all QFs, irrespective of size, to contract to provide capacity, the utilities may want to amend their proposals to distinguish between smaller and larger QFs. Such proposals should be accompanied by sufficient justification, based on system planning needs, for distinguishing property insurance treatment on the basis of QF size.

63. Following Advocacy Staff suggestion, the utilities are directed to investigate the possibilities of obtaining group insurance for smaller QFs.

Force Majeure

64. Both MPC and PP&L proposed force majeure clauses in their standard contract which specifically excluded nonavailability of fuel or lack of motive force to operate QF's facility. PP&L exempted small hydro projects from this exclusion on the rationale that, like PP&L, such projects are susceptible to dry water years that are beyond the control of the operator.

The Commission finds that it is unreasonable to give small hydro development deferential treatment when other types of small power production or cogeneration might suffer from similar circumstances. The utilities are directed to include nonavailability of fuel or motive force in their force major clauses. Lack of foreseeability or reasonable control will still be the major determinants as to whether performance will be excused. This provision should not be interpreted to give QFs carte blanche to enter into contractual obligations without reasonable engineering, meterological, or hydrological studies or economic forecasts.

Capacity Adjustments

65. The utilities argued that if during any contract year a QF fails to deliver sufficient capacity some adjustment to its total annual capacity payment should be made. The Commission agrees. Failure to meet contractual capacity commitments should not be casually disregarded.

66. MPC proposes that if a QF fails to meet its capacity commitment during any 12 hour contract capacity review the QF should lose its right to receive any capacity payments for that entire year; this "all or nothing" approach clearly is inconsistent with the proposition that a QF should be paid for any capacity it actually delivers to a utility. MDU's proposal has the same "all or nothing" effect even though its impact is less drastic -- MDU would only require forfeiture of the QF's right to capacity payments for the month in which the deficiency occurred.

66. Because PP&L's proposal accommodates the notion of paying QFs for the capacity they actually deliver, yet it recognizes that some reasonable adjustment should be made for failure to fulfill contractual obligations, the Commission finds that if a QF fails to deliver capacity according to its commitment it would be appropriate for the utilities to adjust either their annual or monthly capacity payment by a factor of delivered capacity to contracted capacity. The QF will still be paid for each kilowatt it delivers, but the reduced per unit payment will force the QF to realize a loss beyond that which results from the loss of anticipated revenue associated with its decreased capacity production.

67. Additionally the Commission recommends that MPC and MDU incorporate PP&L's idea of using an estimate of capacity capabilities for the initial contract year and then adjusting the second and remaining years according to the QF's demonstrated capacity. MPC and MDU are directed to incorporate this finding into their standard contract.

Payment Options

68. A considerable amount of testimony was provided to the Commission pro and con variations in innovative payment schemes. Dr. Power urged that the utilities provide a variety of payment options to any QF contracting to supply energy and capacity over a four to five year contract term. He specifically addressed payments which were based upon (1) levelized annual payments for energy and capacity as derived from projected avoided costs, (2) a fixed capacity component, increased annually by the general inflation rate, and a variable energy component, based on either the preceding or succeeding years' actual or projected avoided energy costs, and (3) variable capacity and energy payments, based on the current contract year's avoided costs.

69. Mr. Barber too stressed the need for flexibility in payment options, particularly noting the desirability of front loaded contracts. In order to further facilitate QF financing, he also suggested that the utilities be required to sign a contract with a QF for a firm amount, projected over the term of the contract, a number of years before the QF would actually deliver any energy; then when the QF comes on-line, he suggested that payments commence at the higher of the contracted rate (a projection) or the then prevailing avoided cost rate (valuation at time-of-delivery). The Commission finds this proposal to be particularly noteworthy because it would not only give the QF greater flexiblity in financing but it would give system planners considerable lead time to integrate QF production into their resource planning efforts.

70. Of the three utilities, only PP&L presented any alternative method of payment. Their proposal consisted of payments that have been levelized over the term of the contract, based on prices as projected at the time the contract was executed. PP&L's levelized payment option was available only to QFs willing to provide capacity for a period of years. At hearing PP&L withdrew its levelized payment option and justified its action in light of a recent decision by the Oregon Public Utilities Commissioner that required all QFs opting for a levelized payment plan to provide a performance bond. In its rebuttal brief, however, PP&L requested that its initial levelized payment proposal and supporting testimony be reinstated because, on October 29, 1981, the Oregon Public Utilities Commissioner modified his position on performance bonds. Rather than requiring bonds for all QFs opting for levelized payments, the Oregon Commissioner may require, upon utility petition and with good cause shown, QF performance bonds in particular instances.

71. With respect to the offering of levelized and/or front loaded contracts, the Commission merely wishes to remind the parties that this particular issue was, after considerable debate, resolved in rulemaking. ARM 38.5.1903(2)(b) explicitly requires the utilities to offer long-term levelized or frontloading contracts: "...the utility shall offer long-term contracts with qualifying facilities which permit a rate higher than avoided costs in the early years of the contract and a lower rate in the latter years."

72. When the Commission adopted this rule it recognized that front-loaded, or levelized, contracts, would initially aid the QF by covering debt service and ultimately benefit the utility and/or ratepayers by providing power below avoided costs during the second half of the contract. Neither the Commission rule, nor its policy, has changed in the interim.

73. The Commission reinstates and accepts PP&L's levelized payment proposal, with the admonition that Commission rules must not be disregarded merely because another state's regulatory body has taken a different approach to the same issue. MPC and MDU should expand their payment options to comply with Commission rules; their payment options need not mirror PP&L's proposal. As long as the payment option incorporated into the tariff and standard contract embodies the purposes of ARM 38.5.1903(2), MPC and MDU will have discharged their obligation under the rule. The Commission wishes to emphasize, however, that all QFs signing long-term contracts, per Commission rule, are entitled to levelized or front-loaded contracts.

74. Because of the risk associated with nonperformance of front-loaded or levelized contracts PP&L has indicated in its rebuttal brief, that as a matter of corporate policy, all QF contracts of four megawatts or more which contain a levelized payment provision will be submitted to the Commission and that, should PP&L perceive that there is sufficient risk of nonperformance by the QF, PP&L will submit such a contract to the Commission for advance review.

75. The Commission rules do not contemplate advance review and Commission approval of questionable contracts. Although the Commission concedes that PP&L's suggestions may be practical and well conceived, they necessarily place the Commission in a position to set aside a rule when there are no rules or guidelines for doing so. In declining to act as arbitrator regarding prospects of QF nonperformance [dubious QF contracts containing a levelization of payments

provision], the Commission assures the utilities that, should a QF default on a front-loaded or levelized contract and subsequently the QF is discovered to be judgment proof, any losses the utility incurred as a result of complying with this rule will be given appropriate treatment in ratemaking proceedings.

Liquidated Damages

76. The Commission finds that each utility should include a liquidated damages provision in their standard contract. The formulae for calculating the appropriate damages should account for two contingencies: (1) early termination or default on a front-loaded or "levelization of payments" long-term contract and (2) premature termination or default on a nonlevelized long-term contract. The particulars of how to compute these damages will be addressed below; first the Commission wishes to discuss the policy rationale for requiring such a provision.

77. The Commission requires this provision to encourage QFs to accurately assess energy and capacity production capabilities when it commits, and the utility integrates, its production into utility system resource planning under a long-term power contract. As well, the Commission recognizes that it may be very difficult to ascertain the losses either party has experienced as a result of termination or default, however, if a reasonable estimate of those losses can be agreed upon at the time the contract is executed, an additional element of uncertainty can be eliminated from the contract.

78. Although none of the utilities proposed a liquidated damages provision that specifically addressed default or termination of a levelized contract, because MPC's standard contract provided for per unit capacity payments that varied with the term of the contract, that liquidated damages clause can be used for a frame of reference in this instance. Overcollection of payments during the actual term of the contract vis a vis the original term and the impact of unexpired term on system planning were handled separately under MPC's proposal. Differences in the amount of losses estimated due to overcollection were supposedly justified by the nature of the termination. System planning losses were recognized only in the eventuality that minimum notice requirements were not met.

79. Dr. Power suggested that the Commission adopt a repayment (liquidated damages) provision similar to that ordered by the Idaho Public Utilities Commission. There, rather than constructing what could be perceived as serious disincentives to QF development, the Idaho PUC forgave small QFs (less than 1 MW in size) all but a nominal proportion of the damages that could flow from early termination or default and only required larger QFs to repay one-half of what was lost.

80. The Commission rejects the notion that policy considerations warrant encouragement of cogeneration and small power production at any cost: QF accountability for early termination or default-related losses should not be a function of QF size, or the magnitude of the possible loss to the utility implicitly, and/or ratepayers. As of the date of notice of termination or termination, the QF should return the entire difference between the total payments received under the front-loaded contract and the total payments that would have been received had payments been based upon the QF's actual term of performance and avoided capacity and energy rates as projected at the time the contract was executed. The Commission finds this repayment formula not only logical but eminently fair to QFs, utility and ratepayer alike.

81. Because the Commission determined above that, for system planning purposes, a minimum term of four years is required to actually avoid or defer capacity expansion, it follows that the utility will incur minimal, if any, damages should a QF, upon four or more years advance notice, terminate a long-term contract. However, if a utility relies on the continuation of QF capacity in its system planning and a QF prematurely terminates its minimum four year contract or gives less than 48 months notice of its termination, the utility will incur system planning related losses, and the QF should reimburse the utility for the value of the system planning latitude the utility has necessarily forfeited. An amount equal to the average monthly capacity payment times the difference between the lesser of 48 months or the unexpired term of the contract (in months) and the number of months notice given regarding the termination should roughly approximate these losses. The approach the Commission has adopted is a modification of similar proposals from MPC and MDU.

Government Regulation and Termination

82. Burdensome governmental regulation was proffered by the utilities as a suitable justification for almost immediate termination of a QF contract. Irrespective of the fact that they could not envision a utility invoking this provision, the utilities suggested that inclusion of such a provision was primarily to the benefit of the QF.

83. The Commission is not persuaded. The fact that there is no mutuality involved making such a determination suggests that such a clause begs contention and promotes uncertainty as to party responsibilities. The utilities are requested to delete such provisions from their contracts.

CONCLUSIONS OF LAW

1. Montana-Dakota Utilities Company, Montana Power Company and Pacific Light & Power Company are public utilities within the meaning of Montana law, Sections 69-3-101, 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates and terms and conditions for the purchase of electricity by public utilities from qualified cogenerators and small power producers. Sections 69-3-102, 69-3-103 and 69-3-603, MCA.

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

4. The objective of encouraging cogeneration and small power production is promoted by the rates and terms and conditions established by this order.

ORDER

1. MDU, MPC and PP&L shall develop rates which are consistent with the Findings of Fact entered by the Commission in this order. These rates shall be developed as summarized below.

a) avoided energy rates shall be based on (1) for short-term contracts (one year), a one year projection of each utility's short run incremental running costs, and (2) for long-term contracts (four or more years), the annualized costs (per directions set forth in Appendix B) of owning and operating a baseload plant, converted to 4/KWH by using an assumed capacity factor of 70 percent.

b) avoided capacity rates shall be based on the annualized payments can be structured on either an annual or monthly basis. A factor relating a QF's capacity factor to a 85 percent availability factor of a combustion turbine shall be used to determine the capacity payment which a QF is entitled; for short-term energy, on an aggregate capacity payment, equal to one-half of the avoided capacity rate, shall be added to the short-term energy rate.

c) detailed working papers shall be submitted in support of aforementioned rate calculations.

2. MDU, MPC and PP&L shall revise their proposed standard contracts in a manner that is consistent with the Findings of Fact herein.

3. Proposed tariffs, including avoided energy and capacity rates and standard contract, shall be filed with this Commission within forty-five (45) days from the date of this order is issued.

Done and Dated this 4th day of January 1982.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

GORDON E. BOLLINGER, Chairman

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

CLYDE JARVIS, Commissioner

THOMAS J. SCHNEIDER, Commissioner

ATTEST:

By: Iris Basta, Acting Secretary

(SEAL)

NOTE: You may be entitled to judicial review of the final decision in this matter. If no Motion for Reconsideration is filed, judicial review may be obtained by filing a petition for review within thirty (30) days from the service of this order. If a Motion for Reconsideration is filed, a Commission order is final for purpose of appeal upon the entry of a ruling on that motion, or upon the passage of ten (10) days following the filing of that motion. cf. the Montana Administration Procedure Act, esp Sec. 2-4-702, MCA; and Commission Rules of Practice and Procedure, esp 38.2.4806, ARM.

APPENDIX A

SUMMARY OF STANDARD TARIFF RATE SCHEDULES

At the option of the QF, energy and capacity is to be purchased at either 1) the Short-Term Schedule or 2) the Long-Term Schedule.

1) The Short-Term Schedule

- Availability: available to all QFs willing and able to sign the standard contract.

- Rates: all energy and capacity purchased is to be priced, at the option of the QF, at a) the Annual Average Rate or b) the Time Differentiated Rate.

  a) Annual Average Rate

    - X 4/KWH for all KWH purchased, where X equals the annual average projection of short run incremental energy costs plus the aggregate capacity payment.

  b) Time Differentiated Rate (initially, at the option of the utility)

    - X_t 4/KWH for all KWH purchased during time period t, where X equals the projection of short run incremental energy costs during each time period t plus the aggregate capacity payment allocated to each time period t based on hourly loss of load probability.

2) The Long-Term Schedule

- Availability: available to all QFs willing and able to sign the standard contract and a performance contract of duration not less than four years.

- Rates: all energy and contracted capacity is to be priced, at the option of the QF, at a) the Annual Average Rate or b) the Time Differentiated Rate.

  a) Annual Average Rate

APPENDIX B

SUMMARY OF SPECIFIC DIRECTION IN COSTING

- All values are to be inflated/discounted to reflect constant contract year dollars.

- Inflation is to reflect industry specific, regionalized real cost indices.

- Discounting is to reflect standard (e.g. DRI) projections of national general inflation.

- Variables and formulae are defined and an example provided, below.

Definition of Variables

2	= system lambda[1] (4/KWH)
a	= baseload capital cost[2] ($/KW)
b	= combustion turbine capital cost[3] ($/KW)
c	= baseload annual carrying charge[4] (%)
d	= combustion turbine carrying charge (see endnote 4) (%)
e	= baseload fixed O&M[5] ($/KW)
f	= combustion turbine fixed O&M (see endnote 5) ($/KW)
g	= line loss factor[6] (%)
h	= coal cost[7] ($/ton)
i	= coal fuel content (see endnote 7) (BTU/lb)
j	= baseload plant heat rate[8] (BTU/KWH)
k	= baseload variable O&M (see endnote 5) (4/KWH)
cf	= QF capacity factor[9] (KWH/KW)

i) Energy Payment

- X 4/KWH for all KWH purchased, where X equals the annualized unit cost owning and operating a baseload plant, less the annualized unit cost of owning a combustion turbine.

ii) Capacity Payment

- Y $/KW(cf) for all contracted KW, where Y equals the annualized unit cost of a combustion turbine (from 2ai, above) and CF represents the negotiated expected or demonstrated QF plant capacity factor.

b) Time Differentiated Rate (initially, at the option of the utility)

i) Energy Payment

- X_t 4/KWH for all KWH purchased during each time period t where X represents the annualized unit cost of owning and operating a baseload plant less the annualized unit cost of a combustion turbine, differentiated by time period t to reflect short run incremental energy cost variation.

ii) Capacity Payment

- Y_t $/KW for all contracted KW delivered during each time period t, where Y equals the annualized unit cost of combustion turbine (from 2bi, above) differentiated by time period t to reflect the relative probability of capacity shortage in time period t.

Rate Schedule Formulae

short-term energy =

$$2g + \frac{(bd + f).425}{(8760)(.85).85}$$

long-term energy =

$$\frac{((ac + e) - (bd + f))}{(8760).70} g + \frac{hj}{i} + k$$

long-term capacity =

$$\frac{(bd + f)cf}{.85}$$

Example Rate Calculation[10]

2	=	2.50 4/KWH	g	=	8.3%
a	=	1200 $/KW	h	=	10.0 $/ton
b	=	300 $/KW	i	=	9,000 BTU/lb
c	=	16%	j	=	11,000 BTU/KWH
d	=	17%	k	=	.3 4/KWH
e	=	20 $/KW	cf	=	.65 KWH/KW
f	=	10 $/KW			

short-term energy = $.250\,(1.083) + \dfrac{(300(.17) + 10).425}{8760(.85)(.85)}$

= .0271 + .0041
= .0312 $/KWH

<u>long-term energy</u> =

$$\left(\frac{(1200(.16) + 20) - (300(.17) + 10)}{8760(.70)}\right) 1.083 + \frac{(10(11,000))}{(2000(9000))} + .003$$

= .0266 + .0091
= 0357 $/KW

<u>long-term capacity</u> = $\frac{(300(.17) + 10)(.65)}{(.85)}$

= 46.65 $/KW-YR

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1. Short run incremental energy cost via production modeling of economic dispatch. To include variable O&M and revenue requirement associated with working capital and fuel inventory.

2. Actual baseload capital cost estimates to be supported by actual engineering cost study. The capital cost estimates are to be exhaustive and detailed by component. Rather than list the components, the Commission refers you to Appendix A of EPRI=s "Coal-Fired Power Plant Capital Cost Estimates" (Bechtel Power Corporation, May, 1981, report #EPRI PE-1865). Cost estimates will be reviewed with necessary adjustment made as deemed appropriate.

3. Actual combustion turbine capital cost estimate supported by actual engineering cost study, if available, or consistent with industry estimates. Treatment must be equally exhaustive and detailed by component.

4. Annual carrying charges supported by calculations of incremental cost of capital; 35 year book life assigned to baseload plants, 25 for combustion turbines.

5. Appendix A of the EPRI report cited above provides the minimum components to be considered. Includes working capital and variable costs associated with SO2 removal.

6. Initially, equal to 8.3% applied to all energy. Eventually, shall reflect utility specific actual analysis and, in the case of time differentiation, allocated to rating periods commensurate with analysis results.

7. Coal cost and fuel content are to reflect actual contract year purchase contracts. Coal cost is to include a separate component reflecting transportation costs.

8. Plant heat rate is to reflect actual plant heat rate at expected operating load.

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9. QF capacity factor is to represent expected performance, initially, and demonstrated performance after first contract year.

10. These values are generally representative of those submitted by intervening parties in this proceeding. Although they are provided for illustrative purposes, they also serve as indicators of what the Commission has found to be reasonable.